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Gretchen King

Gretchen King

APPLICATION FOR UNITED STATES LETTERS PATENT

FOR

NOVEL WELLBORE FLUID CIRCULATION SYSTEM AND METHOD

Inventors: Peter Fontana
Amsterdam, The Netherlands
Roger Fincher
Conroe, Texas
Larry Watkins
Houston, Texas
Peter Aronstam
Houston, Texas

Assignee: Baker Hughes Incorporated
3900 Essex Lane, Suite 1920
Houston, Texas 77027

CROSS-REFERENCE TO RELATED APPLICATIONS

This application takes priority from United States Provisional Patent Application Serial No. 60/428,423, filed November 22, 2002.

BACKGROUND OF THE INVENTION

Field of the Invention

This invention relates generally to oilfield wellbore drilling systems and more particularly to drilling fluid circulation systems that utilize a wellbore fluid circulation device to optimize drilling fluid circulation.

Background of the Art

Oilfield wellbores are drilled by rotating a drill bit conveyed into the wellbore by a drill string. The drill string includes a drill pipe (tubing) that has at its bottom end a drilling assembly (also referred to as the "bottomhole assembly" or "BHA") that carries the drill bit for drilling the wellbore. The drill pipe is made of jointed pipes. Alternatively, coiled tubing may be utilized to carry the drilling of assembly. The drilling assembly usually includes a drilling motor or a "mud motor" that rotates the drill bit. The drilling assembly also includes a variety of sensors for taking measurements of a variety of drilling, formation and BHA parameters. A suitable drilling fluid (commonly referred to as the "mud") is supplied or pumped under pressure from a source at the surface down the tubing. The drilling fluid drives the mud motor and then discharges at the bottom of the drill bit. The drilling fluid returns uphole via the annulus between the drill string and the wellbore inside and carries with it pieces of formation (commonly referred to as the "cuttings") cut or produced by the drill bit in drilling the wellbore.

For drilling wellbores under water (referred to in the industry as "offshore" or "subsea" drilling) tubing is provided at a work station (located on a vessel or

platform). One or more tubing injectors or rigs are used to move the tubing into and out of the wellbore. In riser-type drilling, a riser, which is formed by joining sections of casing or pipe, is deployed between the drilling vessel and the wellhead equipment at the sea bottom and is utilized to guide the tubing to the wellhead. The riser also serves as a conduit for fluid returning from the wellhead to the sea surface.

During drilling with conventional drilling fluid circulation systems, the drilling operator attempts to carefully control the fluid density at the surface so as to control pressure in the wellbore, including the bottomhole pressure. Referring to **Figure 1A**, there is shown a surface pump **P1** at the surface **S1** for pumping a supply fluid **SF1** via a drill string **DS1** into a wellbore **W1**. The return fluid **RF1** flows up an annulus **A1** formed by the drill string **DS1** and wall of the wellbore **W1**. The drilling fluid in the annulus **A1** carries with it the cuttings **C1** generated by the cutting action of a drill bit (not shown). The drill string **DS 1** is shown separately from the wellbore **W1** to better illustrate the flow path of the circulating drilling fluid. Typically, the operator maintains the hydrostatic pressure of the drilling fluid in the wellbore above the formation or pore pressure to avoid well blow-out. Under this regime, the surface pump **P1** has the burden of flowing the drilling fluid down the drill string **DS1** and also upwards along the annulus **A1**. Accordingly, the surface pump **P1** must overcome the frictional losses along both of these paths. Moreover, the surface pump **P1** must maintain a flow rate in the annulus **A1** that provides sufficient fluid velocity to carry entrained cuttings **C1** to the surface. Thus, in this conventional arrangement, the pumping capacity of the surface pump **P1** is typically selected to (i) overcome frictional losses present as the drilling fluid flows through the drill string **DS1** and the annulus **A1**; and (ii) provide a flow velocity or flow rate that can carry or lift the cuttings **C1** through the annulus **A1**. It will be appreciated that such pumps must have relatively large pressure and flow rate capacities. Furthermore, these relatively large pressures can damage the exposed formation **F1** (or "open hole") below the casing **CA1**.

For instance, the fluid pressure needed to provide the desired fluid flow rate can fracture the rock or earth forming the wall of the wellbore **W1** and thereby compromise the integrity of the wellbore **W1** at the exposed and unprotected formation **F1**.

In another conventional drilling arrangement shown in **Figure 1B**, there is shown a pump **P2** at the surface for pumping a supply fluid **SF2** via an annulus **A2** into a wellbore **W2**. The return fluid **RF2** flows up the drill string **DS2** carrying with it the entrained cuttings **C2**. In this regime, the surface pump **P2** also has the burden of flowing the drilling fluid down the drill string **DS2** and also upwards along the annulus **A2**. Accordingly, the surface pump **P2** must overcome the frictional losses along both of these paths. Further, because the cross-sectional area of the drill string **DS2** is smaller than the cross sectional area of the annulus **A2**, the density of the return fluid **RF2** and cuttings **C2** flowing in the drill string **DS2** is higher than the density of the return fluid **RF1** and cuttings in the annulus **A1** of **Figure 1A** under similar drilling conditions (*e.g.*, the same rate of penetration (ROP)). This higher fluid density requires a correspondingly higher pressure differential and flow rate in order to lift the cuttings **C2** to the surface **S2**. Thus, in this conventional arrangement, the pumping capacity of the surface pump **P2** is typically selected to (i) overcome frictional losses present as the drilling fluid flows through the annulus A and the drill string **DS2**; and (ii) provide a flow velocity or flow rate that can carry or lift the cuttings **C2** through the annulus **A2**. It will be appreciated that such pumps must also have relatively large pressure and flow rate capacities.

The present invention addresses these and other drawbacks of conventional fluid circulation systems for supporting well construction activity.

SUMMARY OF THE INVENTION

The present invention provides wellbore systems for performing downhole wellbore operations for both land and offshore wellbores. Such drilling systems include a rig that moves an umbilical (*e.g.*, drill string) into and out of the wellbore. A bottomhole assembly, carrying the drill bit, is attached to the bottom end of the drill string. A well control assembly or equipment on the wellhead receives the bottomhole assembly and the umbilical. A drilling fluid system supplies a drilling fluid via a fluid circulation system having a supply line and a return line. During operation, drilling fluid is fed into the supply line, which can include an annulus formed between the umbilical and the wellbore wall. This fluid washes and lubricates the drill bit and returns to the well control equipment carrying the drill cuttings via the return line, which can include the umbilical.

In one embodiment of the present invention, a fluid circulation device, such as a positive displacement or centrifugal pump, positioned along the return line provides the primary motive force for circulating the drilling fluid through the supply line and return line of the fluid circulation system. By "primary motive force," it is meant that operation of the fluid circulation device provides the majority of the force or differential pressure required to circulate drilling fluid through the supply line and return line. In a separate arrangement, one or more supplemental fluid circulation devices are coupled to the supply line and/or return line to assist in circulating drilling fluid. By "supplemental," it is meant that these additional fluid circulation devices are task-specific (*e.g.*, providing zones of higher or lower fluid pressure/flow rates, improve bit cleaning, and/or overcoming circulation losses in specific segments of the fluid circulation system), but primarily operate in cooperation with the fluid circulation device. The fluid circulation device can be any device adapted to actively induce flow or controlled movement of a fluid body or column. Such devices can include centrifugal pumps, positive displacement pumps, piston-type pumps, jet pumps, magneto-hydrodynamic drives, and other like devices. In one embodiment of the present

invention, the operation of the fluid circulation device is generally independent of the operation of the drill bit. For instance, the flow rate or pressure differential provided by the fluid circulation device can be controlled without necessarily adjusting the rotational speed of the drill bit or the driver (*e.g.*, rotating drill string) rotating the drill bit. A controller in the system may be utilized to control the operation of the fluid circulation device according to programmed instructions and/or in response to a parameter of interest, which may be pressure, fluid flow, a characteristic of the wellbore fluid or the formation of any other suitable downhole or surface measured parameter.

The system also includes downhole devices for performing a variety of functions. Exemplary downhole devices include devices that control the drilling fluid flow rate and flow paths. For example, the system can include one or more flow-control devices that can stop the flow of the fluid in the umbilical and/or the annulus. Such flow-control devices can be configured to direct fluid from the annulus into the umbilical. Another exemplary downhole device can be configured for processing the cuttings (*e.g.*, reduction of cutting size) and other debris flowing in the return line. For example, a comminution device can be disposed in the return line upstream of the fluid circulation device.

In one embodiment, sensors communicate with a controller via a telemetry system control the drilling activity according to one or more parameters (*e.g.*, a specified range of the wellbore pressure at a zone of interest or specified rate of penetration). The sensors are strategically positioned throughout the system to provide information or data relating to one or more selected parameters of interest such as drilling parameters, drilling assembly or BHA parameters, and formation or formation evaluation parameters. The controller suitable for drilling operations can include programs for maintaining drilling activity within the specified parameter or parameters. The controller may be

programmed to activate downhole devices according to programmed instructions or upon the occurrence of a particular condition.

In one embodiment, a well bore assembly utilizing a bit rotated by a downhole motor and a fluid circulation device driven by an associated motor. A power transmission line or conduit supplies power to the each of the motors. Additionally, the wellbore assembly can includes a controller coupled to sensors configured to measure one or more parameters of interest (*e.g.*, pressure of the supply fluid). In one arrangement, the motors are variable speed electric motors that are adapted for use in a wellbore environment. Other embodiments of motors can be operated by pressurized gas, hydraulic fluid, and other energy streams supplied from a surface location. Other equally suitable arrangements can include a single motor (electric or otherwise) that drives both the bit and the fluid circulation device. In another embodiment, the wellbore system includes a downhole power unit for energizing one or more of the motors. The stored energy supply, in certain embodiments, is replenished from a surface source. Further, a plurality of fluid circulation devices can be positioned serially or in parallel along the return line.

Examples of the more important features of the invention have been summarized (albeit rather broadly) in order that the detailed description thereof that follows may be better understood and in order that the contributions they represent to the art may be appreciated. There are, of course, additional features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

For detailed understanding of the present invention, reference should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawing:

Figure 1A is a schematic illustration of one conventional arrangement for circulating fluid in a wellbore;

Figure 1B is a schematic illustration of another conventional arrangement for circulating fluid in a wellbore;

Figure 2 is a schematic illustration of an exemplary arrangement for circulating fluid in a wellbore according to one embodiment of the present invention;

Figure 3 is a schematic elevation view of well construction system using a fluid circulation device made in accordance with one embodiments of the present invention;

Figure 4 is a schematic illustration of one embodiment of an arrangement according to the present invention wherein a wellbore system uses a fluid circulation device energized by a surface source; and

Figure 5 is a schematic illustration of one embodiment of an arrangement according to the present invention wherein a wellbore system uses a fluid circulation device energized by a local (wellbore) source.

DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

Referring initially to Figure **2**, there is schematically illustrated a well construction facility **10** for forming a wellbore **12** in an earthen formation **14**. The facility **10** includes a rig **16** and known equipment such as a wellhead, blow-out preventers and other components associated with the drilling, completion and/or workover of a hydrocarbon producing well. For clarity, these components are not

shown. Moreover, the rig **16** may be situated on land or at an offshore location. In accordance with one embodiment of the present invention, the facility **10** includes a fluid circulation system **18** for providing drilling fluid to a downhole tool or drilling assembly **19**. One exemplary fluid circulation system **18** includes a surface mud supply **20** that provides drilling fluid into a supply line **22**. This drilling fluid circulates through the wellbore **12** and returns via a return line **24** to the surface. For clarity, the downward flow of drilling fluid is identified by arrow **26** and the upward flow of drilling fluid is identified by arrow **28**. The term "line" as used in supply line **22** and return line **24** should be construed in its broadest possible sense. A line can be formed of one continuous conduit, path or channel or a series of connected conduits, paths or channels suitable for conveying a fluid. The line can be co-axial or concentric with another line and include cross-flow subs. Moreover, the line can include man-made sections (tubulars) and/or earthen sections (e.g., an annulus). Conventionally, a casing **33** for providing structural integrity is installed in at least a portion the wellbore **12**, the portion below the casing **33** being generally referred to as "open hole" or exposed formation **31**. During drilling, the drilling fluid flowing uphole, shown by arrow **28**, will have entrained rock and earth formed by a drill bit (also referred to as "return fluid"). In one exemplary arrangement, the supply line **22** can include an annulus **35** of the wellbore **12** and the return line **24** can include drill string, a coiled tubing, a casing, a liner, an umbilical, and/or other tubular member connecting a downhole tool, bottomhole assembly, or drilling assembly **19** to the rig **16**.

In one embodiment, a fluid circulation device **30** is positioned in the return line **24** above or uphole of a well bottom **32**. The fluid circulation device **30** provides the primary motive force for causing drilling fluid to flow or circulate down through the supply line **22** and up through the return line **24**. By "primary motive force," it is meant that operation of the fluid circulation device provides the majority of the force or pressure differential required to circulate drilling fluid

through the supply line **22**, the BHA **19** and return line **24**. In one arrangement, the operation of the fluid circulation device **30** is substantially independent of the operation of the drill bit (not shown) of the BHA **19**. For example, the flow rate or pressure differential provided by the fluid circulation device **30** can be controlled without having to alter drill bit rotation (RPM). Thus, the operational parameters of the fluid circulation device can be controlled without necessarily reducing or increasing the rotational speed, torque, or other operational parameter of the bit or the drill string rotating the drill bit. Such an arrangement can, for instance, enable circulation of drilling fluid even when the drill bit either does not rotate or rotates a minimal amount. It should be understood that the fluid circulation device can be any device, arrangement, or mechanism adapted to actively induce flow or controlled movement of a fluid body or column. Such devices can include mechanical, electro-mechanical, hydraulic-type systems such as centrifugal pumps, positive displacement pumps, piston-type pumps, jet pumps, magneto-hydrodynamic drives, and other like devices.

Operation of the fluid circulation device **30** creates, in certain arrangements, a pressure differential that causes the otherwise mostly static fluid column in the supply line **22** (along with drill cuttings) to be drawn across the BHA **19** and into the return line **24** at the vicinity of the well bottom **32**. To the extent needed to maintain a specified flow rate, the fluid circulation device **30** can increase the flow rate of the fluid in the supply line **22** by increasing the pressure differential in the vicinity of the well bottom **32**. The fluid circulation device **30** also provides sufficient "lifting" force to flow the return fluid and entrained cuttings to the surface through the return line **24**. It should therefore be appreciated that the fluid circulation device **30** can actively induce fluid circulation in both the supply line **22** and the return line **24**.

In one exemplary deployment, the mud supply **20** fills the supply line **22** with drilling fluid by allowing gravity to flow the drilling fluid toward the well bottom **32**. Other suitable devices could include small surface pumps for providing

pressure necessary to convey the drilling fluid to the inlet of supply line **22**. In another exemplary arrangement, supplemental fluid circulation devices (not shown) can be coupled to the supply line **22** and/or return line **24** to assist in circulating drilling fluid. By "supplemental," it is meant that these additional fluid circulation devices circulate drilling fluid to provide a motive force to overcome specific factors but primarily operate in cooperation with the fluid circulation device **30**. For example, a supplemental fluid circulation device can be coupled to the supply line **22** to vary the pressure or flow rate in the fluid column in the supply line **22** a predetermined amount; *e.g.*, an amount sufficient to offset circulation losses in the supply line **22**. Thus, in contrast to conventional fluid circulation systems, the burden of circulating drilling fluid into and out of the wellbore is taken up by a fluid circulation device disposed in the wellbore along the return line rather than by fluid circulation devices at the surface ends of the supply line **22** and the return line **24**.

In certain embodiments, the system **10** can also include a controller **34** for controlling the fluid circulation device **30**. An exemplary controller **34** controls the fluid circulation device **30** in response to signals transmitted by one or more sensors (not shown) that are indicative of one or more of: pressure, fluid flow, a formation characteristic, a wellbore characteristic and a fluid characteristic, a surface measured parameter or a parameter measured in the drill string. The controller **34** can include circuitry and programs that can, based on received information, determine the operating parameters that provide optimal drilling conditions (rate of penetration, well bore stability, optimized drilling flow rate, etc.)

Referring now to Figures **1A**, **1B** and **2**, it will apparent to one skilled in the art that the **Figure 2** embodiment of the present invention has a number of advantages over conventional drilling fluid circulation systems. First, in contrast to conventional arrangements wherein a surface pump must "push" fluid through both the supply line, the BHA and return line, the fluid circulation device **30**, the

device for providing the primary motive force for fluid circulation, is strategically positioned in the return line. Thus, the fluid circulation device **30** need only be configured to "push" fluid through the return line. A passive mechanism, such as gravity-assisted flow, can be use to flow drilling fluid along the annulus **35**. Thus, because the fluid circulation device **30** actively flows drilling fluid through roughly half of the fluid circuit, the power requirements of the fluid circulation device **30** are reduced to some degree. Additionally, the fluid circulation device **30** primarily acts upon the fluid flowing through the return line **24** (e.g., an umbilical such as a drill string) not on the fluid flowing in the annulus and, in particular, the fluid flowing in the portion exposed to the formation **31**. Thus, operation of the fluid circulation device **30** does not increase the fluid pressure in the drilling fluid residing in the open hole section **31** of the wellbore **12**. Advantageously, therefore, circulation of drilling fluid is provided in the fluid circuit servicing the wellbore **32** without creating fluid pressures in the annulus **35** that could damage the earth and rock making up the formation. Stated differently, the fluid circulation device **30** is advantageously positioned to allow the primary motive force or differential needed to circulate drilling fluid to act upon fluid confined within the return line **24** so as to maintain a relatively benign pressure in the fluid column in the annulus **34**.

The numerous embodiments and adaptations of the present invention will be discussed in further detail below.

Referring now to **Figure 3**, there is schematically illustrated a system **100** for performing one or more operations related to the construction, logging, completion or work-over of a hydrocarbon producing well. In particular, **Figure 3** shows a schematic elevation view of one embodiment of a wellbore drilling system **100** for drilling wellbore **32**. The drilling system **100** includes a drilling platform **102**. The platform **102** can be situated on land or can be a drill ship or another suitable surface workstation such as a floating platform or a semi-

submersible for offshore wells. For offshore operations, additional known equipment such as a riser and subsea wellhead will typically be used. To drill a wellbore **32**, well control equipment **104** (also referred to as the wellhead equipment) is placed above the wellbore **32.** The wellhead equipment **104** includes a blow-out-preventer stack **106** and a lubricator (not shown) with its associated flow control.

This system **100** further includes a well tool such as a drilling assembly or a bottomhole assembly ("BHA") **108** at the bottom of a suitable umbilical such as umbilical **110**. In one embodiment, the BHA **108** includes a drill bit **112** adapted to disintegrate rock and earth. The umbilical **110** can be formed partially or fully of drill pipe, metal or composite coiled tubing, liner, casing or other known members. Additionally, the umbilical **110** can include data and power transmission carriers such fluid conduits, fiber optics, and metal conductors. To drill the wellbore **32**, the BHA **108** is conveyed from the drilling platform **102** to the wellhead equipment **104** and then inserted into the wellbore **32**. The umbilical **110** is moved into and out of the wellbore **32** by a suitable tubing injection system.

In accordance with one aspect of the present invention, the drilling system **100** includes a fluid circulation system **120** that includes a surface mud system **122**, a supply line **124**, and a return line **126**. The supply line **124** includes an annulus **35** formed between the umbilical **110** and the casing **128** or wellbore wall **130**. During drilling, the surface mud system **122** supplies a drilling fluid to the supply line **124**, the downward flow of the drilling fluid being represented by arrow **132**. The mud system **122** includes a mud pit or supply source **134**. In exemplary offshore configurations, the source **134** can be at the platform, on a separate rig or vessel, at the seabed floor, or other suitable location. In one embodiment, the source **134** is a variable volume tank positioned at a seabed floor. While gravity may be used as the primary mechanism to induce flow

through the umbilical **110**, one or more pumps **136** may be utilized to assist the flow of the drilling fluid **35**. The drill bit **112** disintegrates the formation (rock) into cuttings (not shown). The drilling fluid leaving the drill bit travels uphole through the return line **126** carrying the drill cuttings therewith (a "return fluid"). The return line **126** can convey the return fluid to a suitable storage tank at a seabed floor, to a platform, to a separate vessel, or other suitable location. In one embodiment, the return fluid discharges into a separator (not shown) that separates the cuttings and other solids from the return fluid and discharges the clean fluid back into the mud pit **134** at the surface or an offshore platform.

Once the well **32** has been drilled to a certain depth, casing **128** with a casing shoe **138** at the bottom is installed. The drilling is then continued to drill the well to a desired depth that will include one or more production sections, such as section **140**. The section below the casing shoe **138** may not be cased until it is desired to complete the well, which leaves the bottom section of the well as an open hole, as shown by numeral **142**.

As noted above, the present invention provides a drilling system for controlling bottomhole pressure at a zone of interest designated by the numeral **140** and also optimize drilling parameters such as drilling fluid flow rate and rate of penetration. In one embodiment of the present invention, a fluid circulation device **150** is fluidicly coupled to return line **126** downstream of the zone of interest **140**. The fluid circulation device is device that is capable of inducing flow of fluid in the supply line **124** and the return line **126**, such as by creating a pressure differential "ΔP" across the device. Thus, the fluid circulation device **126** produces a sufficient suction pressure at the drill bit **112** to draw in the drilling fluid within the supply line **124** (annulus **91**) and "lift" or flow the drilling fluid and entrained cuttings to the surface via the return line **126**. Additionally, by producing a controlled pressure drop, the fluid circulation device **150** reduces upstream pressure, particularly in zone **140**. The fluid circulation device **150** in

certain arrangements can be a suitable pump, e.g., a multi-stage centrifugal-type pump. Moreover, positive displacement type pumps such a screw or gear type or moineau-type pumps may also be adequate for many applications. For example, the pump configuration may be single stage or multi-stage and utilize radial flow, axial flow, or mixed flow.

The system **100** also includes downhole devices that separately or cooperatively perform one or more functions such as controlling the flow rate of the drilling fluid and controlling the flow paths of the drilling fluid. For example, the system **100** can include one or more flow-control devices that can stop the flow of the fluid in the umbilical **110** and/or the annulus **35**. **Figure 1A** shows an exemplary flow-control device **152** that includes a device **154** that can block the fluid flow within the umbilical **110** and a device **156** that blocks can block fluid flow through the annulus **35**. The device **152** can be activated when a particular condition occurs to insulate the well above and below the flow-control device **152**. For example, the flow-control device **152** may be activated to block fluid flow communication when drilling fluid circulation is stopped so as to isolate the sections above and below the device **152**, thereby maintaining the wellbore below the device **152** at or substantially at the pressure condition prior to the stopping of the fluid circulation.

The flow-control devices **154, 156** can also be configured to selectively control the flow path of the drilling fluid. For example, the flow-control device **154** in the umbilical **110** can be configured to direct some or all of the fluid in the annulus **35** into umbilical **110**. Such an operation may be used, for example, to reduce the density of the cuttings-laden fluid flowing in the umbilical **110**. The flow-control device **156** may include check-valves, packers and any other suitable device. Such devices may automatically activate upon the occurrence of a particular event or condition.

The system **100** also includes downhole devices for processing the cuttings (*e.g.*, reduction of cutting size) and other debris flowing in the umbilical **110**. For example, a comminution device **160** can be disposed in the umbilical **110** upstream of the fluid circulation device **150** to reduce the size of entrained cutting and other debris. The comminution device **160** can use known members such as blades, teeth, or rollers to crush, pulverize or otherwise disintegrate cuttings and debris entrained in the fluid flowing in the umbilical **110**. The comminution device **160** can be operated by an electric motor, a hydraulic motor, by rotation of drill string or other suitable means. The comminution device **160** can also be integrated into the fluid circulation device **150**. For instance, if a multi-stage turbine is used as the fluid circulation device **150,** then the stages adjacent the inlet to the turbine can be replaced with blades adapted to cut or shear particles before they pass through the blades of the remaining turbine stages.

Sensors $\mathbf{S_{1-n}}$ are strategically positioned throughout the system **100** to provide information or data relating to one or more selected parameters of interest (pressure, flow rate, temperature). In one embodiment, the devices **20** and sensors $\mathbf{S_{1-n}}$ communicate with a controller **170** via a telemetry system (not shown). Using data provided by the sensors $\mathbf{S_{1-n}}$, the controller **170** can, for example, maintain the wellbore pressure at zone **140** at a selected pressure or range of pressures and/or optimize the flow rate of drilling fluid. The controller **170** maintains the selected pressure or flow rate by controlling the fluid circulation device **150** (e.g., adjusting amount of energy added to the return line **126**) and/or other downhole devices (e.g., adjusting flow rate through a restriction such as a valve).

When configured for drilling operations, the sensors $\mathbf{S_{1-n}}$ provide measurements relating to a variety of drilling parameters, such as fluid pressure, fluid flow rate, rotational speed of pumps and like devices, temperature, weight-

on bit, rate of penetration, etc., drilling assembly or BHA parameters, such as vibration, stick slip, RPM, inclination, direction, BHA location, etc. and formation or formation evaluation parameters commonly referred to as measurement-while-drilling parameters such as resistivity, acoustic, nuclear, NMR, etc. One exeplary type of sensor is a pressure sensor for measuring pressure at one or more locations. Referring still to **Fig. 1A**, pressure sensor $\mathbf{P_1}$ provides pressure data in the BHA, sensor $\mathbf{P_2}$ provides pressure data in the annulus, pressure sensor $\mathbf{P_3}$ in the supply fluid, and pressure sensor $\mathbf{P_4}$ provides pressure data at the surface. Other pressure sensors may be used to provide pressure data at any other desired place in the system **100**. Additionally, the system **100** includes fluid flow sensors such as sensor **V** that provides measurement of fluid flow at one or more places in the system.

Further, the status and condition of equipment as well as parameters relating to ambient conditions (e.g., pressure and other parameters listed above) in the system **100** can be monitored by sensors positioned throughout the system **100**: exemplary locations including at the surface (**S1**), at the fluid circulation device **150** (**S2**), at the wellhead equipment **104** (**S3**), in the supply fluid (**S4**), along the umbilical **110** (**S5**), at the well tool **108** (**S6**), in the return fluid upstream of the fluid circulation device **150** (**S7**), and in the return fluid downstream of the fluid circulation device **150** (**S8**). It should be understood that other locations may also be used for the sensors $\mathbf{S_{1\text{-}n}}$.

The controller **170** for suitable for drilling operations can include programs for maintaining the wellbore pressure at zone **140** at under-balance condition, at at-balance condition or at over-balanced condition. The controller **170** includes one or more processors that process signals from the various sensors in the drilling assembly and also controls their operation. The data provided by these sensors $\mathbf{S_{1\text{-}n}}$ and control signals transmitted by the controller **170** to control downhole devices such as devices **150-158** are communicated by a suitable two-

way telemetry system (not shown). A separate processor may be used for each sensor or device. Each sensor may also have additional circuitry for its unique operations. The controller **170**, which may be either downhole or at the surface, is used herein in the generic sense for simplicity and ease of understanding and not as a limitation because the use and operation of such controllers is known in the art. The controller **170** can contain one or more microprocessors or micro-controllers for processing signals and data and for performing control functions, solid state memory units for storing programmed instructions, models (which may be interactive models) and data, and other necessary control circuits. The microprocessors control the operations of the various sensors, provide communication among the downhole sensors and provide two-way data and signal communication between the drilling assembly **30**, downhole devices such as devices **150-158** and the surface equipment via the two-way telemetry. In other embodiments, the controller **170** can be a hydro-mechanical device that incorporates known mechanisms (valves, biased members, linkages cooperating to actuate tools under, for example, preset conditions).

For convenience, a single controller **170** is shown. It should be understood, however, that a plurality of controllers **170** can also be used. For example, a downhole controller can be used to collect, process and transmit data to a surface controller, which further processes the data and transmits appropriate control signals downhole. Other variations for dividing data processing tasks and generating control signals can also be used. In general, however, during operation, the controller **170** receives the information regarding a parameter of interest and adjusts one or more downhole devices and/or fluid circulation device **150** to provide the desired pressure or range or pressure in the vicinity of the zone of interest **140**. For example, the controller **170** can receive pressure information from one or more of the sensors **(S_1-S_n)** in the system **100**.

As described above, the system **100** in one embodiment includes a controller **170** that includes a memory and peripherals **184** for controlling the operation of the fluid circulation device **150**, the devices **154-158**, and/or the bottomhole assembly **108**. In **Figure 1A**, the controller **170** is shown placed at the surface. It, however, may be located adjacent the fluid circulation device **150**, in the BHA **108** or at any other suitable location. The controller **170** controls the fluid circulation device to create a desired amount of ΔP across the device, which alters the bottomhole pressure accordingly. Alternatively, the controller **170** may be programmed to activate the flow-control devices **154-158** (or other downhole devices) according to programmed instructions or upon the occurrence of a particular condition. Thus, the controller **170** can control the fluid circulation device in response to sensor data regarding a parameter of interest, according to programmed instructions provided to said fluid circulation device, or in response to instructions provided to said fluid circulation device from a remote location. The controller **170** can, thus, operate autonomously or interactively.

During drilling, the controller **170** controls the operation of the fluid circulation device to create a certain pressure differential across the device so as to alter the pressure on the formation or the bottomhole pressure. The controller **170** may be programmed to maintain the wellbore pressure at a value or range of values that provide an under-balance condition, an at-balance condition or an over-balanced condition. In one embodiment, the differential pressure may be altered by altering the speed of the fluid circulation device. For instance, the bottomhole pressure may be maintained at a preselected value or within a selected range relative to a parameter of interest such as the formation pressure. The controller **170** may receive signals from one or more sensors in the system **100** and in response thereto control the operation of the fluid circulation device to create the desired pressure differential. The controller **170** may contain pre-programmed instructions and autonomously control the fluid circulation device or

respond to signals received from another device that may be remotely located from the fluid circulation device.

In certain embodiments, a secondary fluid circulation device **180** fluidicly coupled to the return line **126** cooperates with the fluid circulation device **150** to circulate fluid through the fluid circulation system **120**. In one arrangement, the secondary fluid circulation device **180** is positioned uphole or downstream of the fluid circulation device **150**. Certain advantages can be obtained by dividing the work associated with circulating drilling fluid between two or more downhole fluid circulation devices. One advantage is that the power requirement (*e.g.*, horsepower rating) for the fluid circulation device **150**, which is disposed further downhole that the secondary fluid circulation device **180**, can be reduced. A related advantage is that two separate power supplies can be used to energize each of the devices **150**, **180**. For instance, a surface supplied energy stream (*e.g.*, hydraulic fluid or electricity) can be used to energize the secondary fluid circulation device **180** and a local (wellbore) power supply (*e.g.*, fuel cell) can be used to energize the fluid circulation device **150**. Additionally, different types of devices can be used for each of the devices **150**, **180**. For instance, a centrifugal-type pump may be used for the fluid circulation device **150** and a positive displacement type pump may be used for the secondary fluid circulation device **180**. It should also be appreciated that the devices **150**, **180** (with the associated flow control devices) can be operated to control fluid flow and pressure (or other parameter of interest) in specified or pre-determined zones along the wellbore **32**, thereby providing enhanced control or management of the pressure gradient curve associated with the wellbore **32**.

In certain embodiments, a near bit fluid circulation device **182** in fluid communication with the bit **112** provides a local fluid velocity or flow rate that assists in drawing drilling fluid and cuttings through the bit **112** and up towards the fluid circulation device **150**. In certain instances, the flow rate needed to

efficiently clean the well bottom of cuttings and drilling fluid is higher than that needed to circulate drilling fluid in the wellbore. In one arrangement, the near bit fluid circulation device **182** is positioned sufficiently proximate to the bit **112** to provide a localized flow rate functionally effective for drawing cuttings and drilling fluid away from the bit **112** and into the return line **116**. As is known, efficient bit cleaning leads to high rates of penetration, improved bit wear, and other desirable benefits that result in lower overall drilling costs. In one conventional arrangement, the surface pumps are configured to provide this higher pressure differential, which exposes the open hole portions of the wellbore **32** to potentially damaging higher drilling fluid pressures. In another conventional arrangement, the surface pumps are run to provide only the pressure needed to circulate drilling fluid at the cost of, for example, reduced rates of penetration. As can be appreciated, the near bit fluid circulation device **182** can be configured to provide a flow rate that efficiently cleans the bit **112** of cuttings while the fluid circulation device **150** provides the primary motive force for circulating drilling fluid in the fluid circulation system **120**. The near bit fluid circulation device **182** can be operated in conjunction with or independently of the fluid circulation devices **150**, **180**. For instance, the near bit fluid circulation device **182** can have a dedicated power source or use the power source of the fluid circulation device **150**. Additionally, as noted earlier, different types of devices can be used for each of the devices **150, 180, 182**. It should therefore be appreciated that the near bit fluid circulation device **182** can be configured to provide a localized flow rate to optimize bit cleaning whereas the other fluid circulation devices **150,180** can be configured to optimize the lifting of the return fluid to the surface.

Referring now to **Figure 4**, there is schematically illustrated one exemplary well bore assembly **200** utilizing a bit **202** rotated by a downhole motor **204** and a fluid circulation device **206** driven by an associated motor **208**. A power transmission line or conduit **210** supplies power to the motors **204, 208**. Additionally, the wellbore assembly **200** includes a controller **212**, a sensor **214**

to measure one or more parameters of interest (*e.g.*, pressure) of the return fluid **215** in the return line **126** (umbilical **110**), and a sensor **216** to measure one or more parameters of interest (*e.g.*, pressure) of the supply fluid **217** in the supply line **124** (annulus **91**). In one arrangement, the motors **204, 208** are variable speed electric motors that are adapted for use in a wellbore environment. It should be appreciated that an electrical drive provides a relatively simple method for controlling the fluid circulation device. For instance, varying the speed of the electrical motor will directly control the speed of the rotor in the fluid circulation device, and thus the pressure differential across the fluid circulation device. For such motors, the power transmission line **210** can include embedded metal conductors provided in the umbilical **110** to convey electrical power from a surface location (not shown) to the motors **204, 208** and other equipment (*e.g.*, the controller **212**). Because electric motors are usually more efficient at higher speeds, a suitable fluid circulation device **206** can include a centrifugal type pump or turbine that likewise operate more efficiently at higher speeds. Other embodiments of motors can be operated by pressurized gas, hydraulic fluid, and other energy streams supplied from a surface location, such energy streams being readily apparent to one of ordinary skill in the art. Where appropriate, a positive displacement pump may be used in the fluid circulation device **206**. In one mode of operation, the controller **212** receives signal input from the sensors **214,216**, as well as other sensors **S1-S8 (Figure 3**). The power transmission line **210** can be configured to carry communication signals for enabling two-way telemetric communication between a controller **242** and the surface as well as other downhole equipment. Based on the received sensor data, the controller **212** controls the motors **204, 208** to obtain a bit rotation speed and/or pump flow rate/pressure differential that optimizes one or more selected drilling parameters (*e.g.*, rate of penetration). Other modes of operation have been previously discussed and will not be repeated.

It should be appreciated that **Figur 4** illustrated merely one exemplary well bore assembly. Other equally suitable arrangements can include a single motor (electric or otherwise) that drives both the bit and the fluid circulation device. If the bit and pump are to rotate at different speeds, then a suitable speed/torque conversion unit (not shown) can used to provide a fixed or adjustable speed/torque differential. Alternatively, multiple motors may be used to drive the fluid circulation device and/or the drill bit. By speed/torque conversion unit it is meant known devices such as variable or fixed ratio mechanical gearboxes, hydrostatic torque converters, and a hydrodynamic converters. The controller **212** can optionally be programmed to operate such a speed/torque conversion unit. Still other embodiments can include one or more devices that provide mechanical weight on bit; *e.g.*, thrusters and anchor assemblies. As is known, thrusters can provide an axial thrusting force that urges a drill bit into a formation and thereby enhances bit penetration. Anchors typically engage a wellbore wall with retractable members such as pads to absorb the reaction force produced by the thruster. Thrusters and associated anchors are known in the art and will not be discussed in further detail. Moreover, if the umbilical **110** is drill string, then surface rotation of the drill string **110** can be used to either exclusively or cooperatively rotate the bit **202**. Still further, in yet another embodiment not shown, a cross-flow sub proximate to the drill bit is used to channel fluid from the annulus into the umbilical. Thus, in a conventional manner, the drilling fluid exits the nozzles of the drill bit and enters the annulus with the entrained cuttings. Thereafter, the fluid and entrained cuttings are channeled into the umbilical by the cross-flow sub.

Referring now to **Figure 5**, there is schematically illustrated another exemplary well bore assembly **230** utilizing a bit **232** rotated by a downhole motor **234** and a fluid circulation device **236** driven by an associated motor **238**. A signal transmission line **240** enables two-way telemetric communication between a controller **242** and the surface and can optionally be configured to

transfer power in a manner described below. The wellbore assembly **230** also includes a sensor **244** to measure one or more parameters of interest (*e.g.*, pressure) of the return fluid **215** in the return line (umbilical **110**) and a sensor **246** to measure one or more parameters of interest (*e.g.*, pressure) of the supply fluid **217** in the supply line **124** (annulus **91**). Advantageously, the wellbore system **230** includes a downhole power unit **248** for energizing the motors **238, 234**. In one arrangement wherein the motors **238, 234** are electric, the power unit **248** supplies electrical power by converting a stored energy supply (*e.g.*, a combustible fluid, hydrogen, methanol, or charges of compressed fluids) into electricity. For example, the power unit **248** can include a fuel cell or an internal combustion engine-generator set. The stored energy supply, in certain embodiments, is replenished from a surface source (not shown) via the line **240**. The power supply can also include a geothermal energy conversion unit or other known systems for generating the power used to energize the motors **238,234**. In other arrangements wherein the motor **238, 234** are hydraulic, a suitable hydraulic fluid can be stored in the power unit **248**. Moreover, an intermediate device, such as an electrically-driven pump, can be used to pressurize and circulate this hydraulic fluid.

It should be understood that the **Figure 4** and **5** arrangements can readily be modified to include any or all of the earlier described features; *e.g.*, a plurality of fluid circulation devices positioned serially or in parallel along the return line.

It will be appreciated that many variations to the above-described embodiments are possible. For example, bypass devices, cross-flow subs and conduits (not shown) can be provided to selectively channel fluid around the fluid circulation device. The fluid circulation device is not limited to merely positive displacement pumps and centrifugal type pump. For example, a jet pump can be used. In an exemplary arrangement, a portion of the supply fluid is accelerated by a nozzle and discharged with high velocity into the return line,

thereby effecting a reduction in annular pressure. Pumps incorporating one or more pistons, such as hammer pumps, may also be suitable for certain applications. Additionally, a clutch element can be added to the shaft assembly connecting the drive to the pump to selectively couple and uncouple the drive and pump of a fluid circulation device. Further, in certain applications, it may be advantages to utilize a non-mechanical connection between the drive and the pump. For instance, a magnetic clutch can be used to engage the drive and the pump. In such an arrangement, the supply fluid and drive and the return fluid and pump can remain separated. The speed/torque can be transferred by a magnetic connection that couples the drive and pump elements, which are separated by a tubular element (e.g., drill string).

While the foregoing disclosure is directed to the preferred embodiments of the invention, various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope and spirit of the appended claims be embraced by the foregoing disclosure.